TSX: TVE

Tamarack Valley Energy Ltd. Announces Record 2017 Financial and Operating Results and a 53% Increase in Proved Developed Producing Reserves

Calgary, Alberta – March 6, 2018 – Tamarack Valley Energy Ltd. ("**Tamarack**" or the "**Company**") is pleased to announce its financial and operating results for the three and twelve months ended December 31, 2017 and the results of its independent oil and gas reserves evaluation as of December 31, 2017, prepared by GLJ Petroleum Consultants Ltd. ("GLJ"). Selected financial, operational and reserves information is outlined below and should be read with Tamarack's audited consolidated financial statements ("Financial Statements") and management's discussion and analysis ("MD&A") as of December 31, 2017, which will be filed on SEDAR at www.sedar.com and posted on Tamarack's website at www.tamarackvalley.ca.

2017 Financial and Operating Highlights

- Achieved record corporate production in Q4/17 of 22,807 boe/d, up 11% over Q3/17 of 20,541 boe/d and up 99% over Q4/16 of 11,453 boe/d. Annual production averaged 20,136 boe/d, nearly double Tamarack's 2016 average production of 10,344 boe/d.
- Oil and natural gas liquids ("NGLs") weighting was 62% in Q4/17 compared to 55% in the same period of 2016, representing an increase of 13%, which positively contributed to the Company's stronger netbacks year-over-year. Full year 2017 oil and NGLs weighting increased to 60% compared to 54% for 2016.
- Total adjusted funds flow grew 66% to $57.6 million in Q4/17 ($0.25/share basic and diluted) over Q3/17 ($0.15/share basic and diluted) and increased 182% over Q4/16. Annual 2017 adjusted funds flow of $158.4 million was 147% higher than in 2016.
- Operating netback in Q4/17 increased by 44% over Q3/17 primarily due to the 13% increase in oil and NGLs weighting and the 24% increase in the combined average realized prices for oil and NGLs.
- Production and transportation expenses were reduced by 8% to $10.40/boe in Q4/17 over Q3/17 and were 15% lower than Q4/16.
- Reduced net debt at December 31, 2017 by $21.7 million or 11% quarter-over-quarter, resulting in net debt to annualized Q4/17 adjusted funds flow strengthening to 0.8 times, compared to 1.4 times at the end of Q3/17.
- Proved developed producing reserves ("PDP") grew by 14% per fully diluted share, and reserves on an absolute basis increased by 53% for PDP, 55% for total proved ("TP") and 62% for total proved plus probable ("TPP") compared to 2016.
- Net asset value based on the net present values (discounted at 10%) of the TP and TPP reserves is $2.24 and $4.46 per fully diluted share, respectively. The net present value of reserves has been adjusted for net debt of $173.2 million.
- Achieved attractive capital efficiencies through the 2017 development program, generating a TPP finding and development ("F&D") cost recycle ratio of 1.6 times and a TPP finding, development and acquisition ("FD&A") cost recycle ratio of 1.4 times based on the Q4 2017 operating field netback (excluding hedges) of $28.54/boe.

Financial & Operating Results

	Three months ended December 31, 2017	2016	% change	Years ended December 31, 2017	2016	% change
($ thousands, except per share)						
Total Revenue	**90,160**	39,793	127	**283,672**	115,517	146
Adjusted funds flow[1]	**57,583**	20,453	182	**158,383**	64,164	147
Per share – basic and diluted [1]	**$ 0.25**	$ 0.15	67	**$ 0.70**	$ 0.52	35
Net loss	**(12,525)**	(8,425)	(49)	**(13,924)**	(27,823)	(50)
Per share – basic and diluted	**$ (0.05)**	$ (0.06)	17	**$ (0.06)**	$ (0.23)	(74)
Net debt [1]	**(173,180)**	(52,316)	231	**(173,180)**	(52,316)	231
Capital Expenditures [2]	**35,516**	14,863	139	**192,302**	56,819	238
Weighted average shares outstanding *(thousands)*						
Basic	**228,066**	137,044	66	**225,306**	122,235	84
Diluted	**228,066**	137,044	66	**225,306**	122,235	84
Share Trading						
High	**$ 3.15**	$ 3.89	(19)	**$ 3.59**	$ 4.28	(16)
Low	**$ 2.49**	$ 3.00	(17)	**$ 1.96**	$ 2.16	(9)
Trading volume (thousands)	**35,006**	39,342	(11)	**196,595**	122,074	61
Average daily production						
Light oil (bbls/d)	**12,189**	4,858	151	**9,929**	4,215	136
Heavy oil (bbls/d)	**500**	316	58	**511**	363	41
NGLs (bbls/d)	**1,459**	1,075	36	**1,547**	1,035	49
Natural gas (mcf/d)	**51,956**	31,226	66	**48,893**	28,388	72
Total (boe/d)	**22,807**	11,453	99	**20,136**	10,344	95
Average sale prices						
Light oil ($/bbl)	**65.08**	58.71	11	**59.42**	50.53	18
Heavy oil ($/bbl)	**48.97**	44.60	10	**46.01**	35.45	30
NGLs ($/bbl)	**44.03**	28.99	52	**32.38**	20.74	56
Natural gas ($/mcf)	**1.89**	3.27	(42)	**2.32**	2.41	(4)
Total ($/boe)	**42.97**	37.76	14	**38.60**	30.51	27
Operating netback ($/Boe) [1]						
Average realized sales	**42.97**	37.76	14	**38.60**	30.51	27
Royalty expenses	**(4.03)**	(3.56)	13	**(3.96)**	(2.32)	71
Production expenses	**(10.40)**	(12.17)	(15)	**(11.19)**	(11.64)	(4)
Operating field netback ($/Boe) [1]	**28.54**	22.03	30	**23.45**	16.55	42
Realized commodity hedging gain (loss)	**1.53**	(0.15)	1,120	**0.77**	3.25	(76)
Operating netback	**30.07**	21.88	37	**24.22**	19.80	22
Adjusted funds flow netback ($/Boe) [1]	**27.44**	**19.41**	41	**21.55**	**16.95**	27

Notes:

(1) Adjusted funds flow, net debt, operating netback, operating field netback and adjusted funds flow netback do not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. See "*Oil and Gas Metrics*" and "*Non-IFRS Measures*".

(2) Capital expenditures include exploration and development expenditures, but exclude asset acquisitions and dispositions.

2017 In Review

In January 2017, Tamarack closed the transformative acquisition of strategic Viking assets from Spur Resources, Ltd. (the "Viking Acquisition"), further demonstrating the Company's strategy of adding high-quality, oil-weighted assets which on a half-cycle basis, can achieve a capital cost payout of 1.5 years or less while maintaining balance sheet flexibility. Immediately upon closing, the Company integrated the new Viking assets into its existing operations and through the balance of the year, demonstrated unprecedented growth and operational success. Tamarack increased annual production volumes in 2017 by 95% to 20,136 boe/d (60% liquids), compared to 10,344 boe/d (54% liquids) in 2016 as a direct result of higher production volumes from the Company's successful 2017 drilling program, strong capital efficiencies, and the impact of the Viking Acquisition. In Q4/17, Tamarack achieved record production of 22,807 boe/d and exceeded the Company's original target 2017 exit rate of 21,000 boe/d, which was increased to 22,000 on August 10, 2017.

Recognizing the challenges facing natural gas prices at AECO in 2017, Tamarack made the conscious decision mid-2017 to shift capital to projects with a higher oil and liquids weighting. As such, capital was allocated to the Cardium at Wilson Creek and the Viking at Veteran, resulting in a higher oil-weighting in Q4/17 relative to Q4/16 resulting in stronger netbacks. Tamarack's average per boe sales price increased 27% year-over-year to $38.60/boe in 2017 from $30.51/boe in 2016. This strategic shift had a positive impact on Tamarack's oil and liquids weighting which increased 13% from 55% in Q4/16 to 62% in Q4/17. Although natural gas represented 40% of Tamarack's total production volumes in 2017, it generated less than 15% of the Company's total revenue. For the full year 2017, the Company's oil and liquids weighting averaged 60%, and further increases are expected in 2018 with oil and liquids expected to average 64 to 67% of total production. The shift in production weighting, improved pricing and cost reductions positively impacted Tamarack's operating netbacks (excluding the benefit of hedging), which increased 42% in 2017 to $23.45/boe from $16.55/boe in 2016. The Company's high-quality asset base, increased focus on driving improved margins with oil and liquids production, and adherence to cost control measures contributed to annual adjusted funds flow of $158.4 million ($0.70 per diluted share) compared to $64.2 million ($0.52 per diluted share) in 2016, representing a 147% increase.

Tamarack's ongoing commitment to improve netbacks is not limited to cost reduction initiatives. By November 1, 2017, the Company had also taken proactive steps to mitigate gas price weakness and reduce its exposure to the structurally challenged AECO pricing hub. Effective April 1, 2018, approximately 40% of Tamarack's natural gas production will receive pricing from various markets that have historically outperformed AECO, including Malin (16%), Chicago (8%), Dawn (8%) and Mich Con (8%). In addition, the Company will continue to opportunistically layer in hedges to further protect against downside risk in crude oil and natural gas pricing, as well as foreign exchange movements.

Year-end 2017 net debt totaled $173.2 million, which represents a net debt to fourth quarter 2017 annualized adjusted funds flow ratio of 0.8 times, compared to 0.6 times at December 31, 2016. Tamarack invested $192.3 million in its 2017 capital expenditures program, including $12 million on tuck-in acquisitions in core areas and approximately $8.0 million of capital accelerated from 2018 into the fourth quarter of 2017. The capital acceleration was in response to attaining favorable rates for drilling and completion services and was intended to avoid challenges accessing service crews that were experienced in Q1/17. In Q4/17, Tamarack drilled, completed and equipped three (2.3 net) Redwater oil wells and one (1.0 net) Cardium oil well and brought on production ten (10.0 net) Viking oil wells, three (3.0 net) Cardium oil wells, two (2.0 net) heavy oil wells and one (1.0 net) Penny Barons oil well, which were all drilled prior to the start of the fourth quarter. In addition, Tamarack drilled 15 (14.4 net) Viking oil wells in December, which were fracture stimulated and brought on production in early 2018. Tamarack remains focused on drilling wells which are expected to payout in 1.5 years or less, with a current inventory which could last the Company in excess of eight years.

Tamarack has optimally positioned itself over the course of the past two years to take advantage of the recovering oil and liquids price environment experienced to date in 2018 which is expected to remain robust through the balance of the year. The strategic decisions that Tamarack has made historically, in particular with regards to the Viking Acquisition, have allowed the Company to double production volumes and set the stage for a new standard of operational excellence and shareholder value creation. Tamarack's unique returns-based growth model, financial flexibility and continued focus on operational improvements will continue to unlock the value of its rich asset base.

2017 Year-End Reserves Summary

The impact of Tamarack's strategic shift to direct more capital to oil and liquids projects through 2017 was clearly demonstrated by strengthening of the Company's operating netback, which averaged $28.54/boe in Q4/17. Based on this operating netback, Tamarack generated a TPP F&D recycle ratio of 1.6x, and 1.4x for both TP and PDP, and FD&A recycle ratios of 1.4x for TPP, 1.0x for TP and 0.9x for PDP. The Company maintained a consistent approach to reserves booking, with TPP reserves including only 200 net proved undeveloped horizontal Viking oil drilling locations and 44 net undeveloped horizontal Cardium drilling locations. Further, the future development capital within GLJ's 2017 reserves evaluation for 2018 of $114.3 million and $154.1 million for 2019 is materially lower than Tamarack's current 2018 capital expenditure guidance of $195 to $205 million.

Consistent with Tamarack's focus on increasing its oil and liquids weighting, the Company intends to allocate the majority of its 2018 capital expenditure budget (approximately $145-$150 million) to the areas of Wilson Creek, Veteran and Penny, all of which have locations offering greater than 80% oil weighting. As a result of this budgeting decision, Tamarack anticipates field operating netbacks will further increase through 2018 assuming the current commodity price environment remains stable.

The following tables highlight Tamarack's 2017 year-end independent reserves assessment and evaluation prepared by GLJ with an effective date of December 31, 2017 (the "GLJ Report"). The GLJ Report has been prepared in accordance with definitions, standards and procedures contained in *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook. All evaluations and summaries of future net revenue are stated prior to provision for interest, debt service charges or general and administrative expenses and after deduction of royalties, operating costs, estimated well abandonment and reclamation costs and estimated future capital expenditures. The information included in the "Net Present Values of Future Net Revenue before Income Taxes" table below is based on an average of pricing assumptions prepared by three independent external reserves evaluators. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves.

- PDP reserves increased by 53% per fully-diluted share.
- Increased TP reserves by 55% to 51.8 million boe, and TPP reserves by 62% to 91.5 million boe.
- Oil and NGLs weighting across all reserves categories increased to approximately 62% compared to 2016 weightings of approximately 60%.
- Significant increases in oil reserves of 51%, 55% and 74% on PDP, TP and TPP, respectively, over 2016.
- 2017 TP reserves represents 57% of total TPP reserves compared to 2016 at 59%.
- Including acquisitions, the Company replaced 350% of production on a TP basis and 575% on a TPP basis.
- Achieved TP F&D costs of approximately $20.70/boe and TP FD&A costs of approximately $27.86/boe, both including the change in future development capital ("FDC").
- Achieved TPP F&D costs of approximately $17.88/boe and TPP FD&A costs of approximately $20.91/boe, both including the change in FDC.
- Realized three-year average TPP F&D costs of approximately $13.59/boe and TPP FD&A costs of $16.08/boe, both including the change in FDC.
- Increased TPP reserve life index to 12.4 years based on 2017 average production of 20,136 boe/d.

Reserves Snapshot by Category:

	PDP	TP	TPP
Reserves Added[1] (mboe)	18,166	25,724	42,291
Total Reserves (mboe)[2]	31,333	51,778	91,485
Reserves Replacement	247%	350%	575%
NPV10 BT ($mm)	$479.6	$678.2	$1,178.6
FD&A Cost per boe[3]	$32.51	$27.86	$20.91
Recycle Ratio[4]	0.9x	1.0x	1.4x
F&D Cost per boe [3]	$20.99	$20.70	$17.88
Recycle Ratio[4]	1.4x	1.4x	1.6x

Notes:

(1) This number takes the difference in reserves year over year plus the production for the year.
(2) Total reserves are Company Gross Reserves which exclude royalty volumes.
(3) Including changes in FDC.
(4) Based on Q4 2017 operating netback excluding hedges of $28.54 per boe.

Reserves Data (Forecast Prices and Costs) – Company Gross

	CRUDE OIL[1]		CONVENTIONAL NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mmcf)**	**Net (Mmcf)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED:								
Developed Producing	15,331	13,622	79,309	71,986	2,766	2,178	31,316	27,797
Developed Non-Producing	901	810	6,177	5,259	39	32	1,970	1,718
Undeveloped	10,625	9,455	38,729	35,631	1,396	1,271	18,475	16,665
TOTAL PROVED	**26,857**	**23,887**	**124,214**	**112,875**	**4,200**	**3,481**	**51,761**	**46,181**
PROBABLE	22,556	19,935	86,080	78,162	2,799	2,398	39,701	35,360
TOTAL PROVED PLUS PROBABLE	**49,413**	**43,822**	**210,295**	**191,037**	**6,999**	**5,879**	**91,462**	**81,540**

Notes:

(1) Heavy oil and tight oil included in the crude oil product type represents less than 3.1% of any reserves category and as such is immaterial.
(2) Columns may not add due to rounding.

Net Present Values of Future Net Revenue before Income Taxes Discounted at (% per year)

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% Per Year[1] ($/Boe)
PROVED:						
Developed Producing	763,480	574,178	479,594	418,750	374,925	17.25
Developed Non-Producing	46,668	37,684	32,659	29,273	26,746	19.01
Undeveloped	282,396	223,597	165,940	122,192	89,947	9.96
TOTAL PROVED	**1,092,544**	**835,458**	**678,193**	**570,215**	**491,618**	**14.69**
PROBABLE	1,068,532	703,269	500,394	376,503	295,378	14.15
TOTAL PROVED PLUS PROBABLE	**2,161,076**	**1,538,728**	**1,178,587**	**946,718**	**786,996**	**14.45**

Notes:
(1) Unit values based on Company Interest Reserves.
(2) The prices used to estimate net present values are the average of those used by the largest independent industry reserve evaluators.
(3) Columns may not add due to rounding.

Reconciliation of Company Gross Reserves Based on Forecast Prices and Costs

	MBOE		
FACTORS	Proved	Probable	Proved + Probable
December 31, 2016	33,369	23,129	56,498
Extensions and Improved Recovery[1]	10,159	8,407	18,567
Technical Revisions	1,807	(1,673)	133
Acquisitions	14,666	9,893	24,559
Dispositions	(88)	(133)	(221)
Economic Factors	(803)	79	(724)
Production	(7,350)	-	(7,350)
December 31, 2017	**51,761**	**39,701**	**91,462**

Notes:
(1) Reserves additions under Infill Drilling, Improved Recovery and Extensions are combined and reported as "Extensions and Improved Recovery".
(2) Columns may not add due to rounding.
(3) Company Gross Reserves exclude royalty volumes.

Future Development Capital Costs

The following is a summary of GLJ's estimated future development capital required to bring proved and probable undeveloped reserves on production.

Future Development Capital[1]

(amounts in $000s)	Total Proved	Total Proved + Probable
2018	70,037	114,328
2019	117,080	154,073
2020	134,658	183,613
2021 and Subsequent	39,224	242,746
Total Undiscounted FDC	360,998	694,759
Total Discounted FDC at 10% per year	302,034	553,416

Notes:
(1) FDC as per GLJ independent reserve evaluation effective December 31, 2017 based on GLJ forecast pricing.

FD&A Costs

(amounts in $000s except as noted)	2017 TP	2017 TPP	Three Year Average TP	Three Year Average TPP
FD&A costs, including FDC(1)(2)				
Exploration and development capital expenditures (3)(4)	192,302	192,302	103,064	103,064
Acquisitions, net of dispositions	397,725	397,725	175,733	175,733
Total change in FDC	126,251	293,941	67,805	109,294
Total FD&A capital, including change in FDC	716,278	883,969	346,602	388,091
Reserve additions, including revisions – Mboe	11,128	17,929	6,079	7,598
Acquisitions, net of dispositions – Mboe	14,579	24,339	10,189	16,532
Total FD&A Reserves	25,707	42,268	16,267	24,130
F&D costs, including FDC - $/boe	20.70	17.88	17.35	13.59
Acquisition costs, net of dispositions - $/boe	33.33	23.15	23.67	17.23
FD&A costs, including FDC - $/boe	27.86	20.91	21.31	16.08

Notes:

(1) While NI 51-101 requires that the effects of acquisitions and dispositions be excluded from the calculation of finding and development costs, FD&A costs have been presented because acquisitions and dispositions can have a significant impact on the Company's ongoing reserve replacement costs and excluding these amounts could result in an inaccurate portrayal of the Company's cost structure. Finding and development costs both including and excluding acquisitions and dispositions have been presented above.

(2) The calculation of FD&A costs incorporates the change in FDC required to bring proved undeveloped and developed reserves into production. In all cases, the FD&A number is calculated by dividing the identified capital expenditures by the applicable reserves additions after changes in FDC costs.

(3) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

(4) The capital expenditures also exclude capitalized administration costs.

(5) Columns may not add due to rounding.

(6) Calculations using Company Gross Reserves which exclude royalty volumes.

Operations Update

Given the Company's decision to accelerate some of its Q1 2018 capital into Q4 2017, Tamarack completed its first quarter drilling program in the Alberta Viking and Wilson Creek Cardium areas by mid-February 2018, resulting in the drilling of 30 (29.0 net) horizontal Viking light oil wells, nine (9.0 net) Cardium oil wells, and five (4.7 net) oil wells at Redwater. Based on field estimates for January and February 2018, Tamarack averaged approximately 22,800 boe/d for the first two months of the year, with 15 (14.5 net) Viking and five (5.0 net) Cardium wells yet to be brought on production. The Company is on target to achieve its first half 2018 average production guidance of 22,750 – 23,250 boe/d (64-66% liquids). In addition, the Veteran oil battery expansion to 10,000 bbls/d of oil and 10 mmcf/d of natural gas which was originally scheduled for commissioning in April of 2018 remains on budget and schedule.

Tamarack is pleased to confirm it has entered into an agreement to commit on a take-or-pay basis to deliver at least 4,000 bbls of oil per day to a midstream company's new 120 km pipeline (the "Viking Pipeline Project"). The Viking Pipeline Project will extend the reach of the existing Provost pipeline and support Tamarack's planned development of the Veteran Viking oil play by ensuring the Company has access to oil markets, with initial capacity of 13,300 bbls/d and the potential to expand up to 25,000 bbls/d. This contract will eliminate the need for Tamarack to truck oil sales to markets and is anticipated to reduce Veteran operating costs by approximately $1.45/boe contributing to corporate production and transportation cost savings of approximately $0.40 to $0.50/boe in 2019. The midstream company has indicated the Viking Pipeline Project is expected to be operational by the end of the first quarter of 2019.

In 2018, Tamarack projects to achieve 10-15% debt adjusted production per share growth over the 2017 average, maintain net debt to annualized Q4/18 adjusted funds flow of less than one times and improve liquids weighting resulting in increased netbacks. Tamarack's business remains solid and at times management believes the Company's prevailing share price does not adequately reflect the underlying value of its assets. As such, Tamarack has received Board approval to make an application to implement a normal course issuer bid ("NCIB") through the facilities of the Toronto Stock Exchange and alternate trading platforms, pursuant to which Tamarack would have the option to repurchase its common shares for cancellation. The NCIB represents an additional tool that can be employed as part of management's ongoing strategy to increase long-term shareholder value.

2018 Guidance

The Company reiterates 2018 guidance as outlined below:

- Annual average production between 22,500 – 23,500 boe/d (64-66% oil and liquids), with 2018 exit production estimated between 24,000 – 24,500 boe/d (65-67% oil and liquids);
- Capital expenditure range of $195 to $205 million, weighted approximately equally between the first and second halves;
- Estimated year end 2018 net debt to fourth quarter annualized adjusted funds flow ratio of less than 1.0 times with an estimated $100 million of liquidity on the Company's existing credit facilities; and
- Assumed 2018 commodity prices averaging approximately: WTI US$56.75/bbl, Edmonton Par price averaging C$64.60/bbl, AECO averaging $1.65/GJ and a Canadian/US dollar exchange rate of $0.79. Tamarack has also assumed an interest rate increase of 0.5% in 2018.

About Tamarack Valley Energy Ltd.

Tamarack is an oil and gas exploration and production company committed to long-term growth and the identification, evaluation and operation of resource plays in the Western Canadian Sedimentary Basin. Tamarack's strategic direction is focused on two key principles – targeting repeatable and relatively predictable plays that provide long-life reserves, and using a rigorous, proven modeling process to carefully manage risk and identify opportunities. The Company has an extensive inventory of low-risk, oil development drilling locations focused primarily in the Cardium and Viking fairways in Alberta that are economic over a range of oil and natural gas prices. With this type of portfolio and an experienced and committed management team, Tamarack intends to continue delivering on its strategy to maximize shareholder returns while managing its balance sheet.

Abbreviations

bbls	barrels
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousands barrels of oil equivalent
mcf	thousand cubic feet
GJ	gigajoule
MMcf	million cubic feet
Mbbls	thousand barrels
mcf/d	thousand cubic feet per day
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
AECO	the natural gas storage facility located at Suffield, Alberta connected to TransCanada's Alberta System
IFRS	International Financial Reporting Standards as issued by the International Accounting Standards Board

Oil and Gas Advisories

Unit Cost Calculation. For the purpose of calculating unit costs, natural gas volumes have been converted to a barrel of oil equivalent using six thousand cubic feet equal to one barrel unless otherwise stated. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms with Canadian Securities Regulators' NI 51–101. Boe's may be misleading, particularly if used in isolation.

Drilling Locations. In this press release, the 1,250 net drilling locations identified include 266 net proved locations, 245 net probable locations and 739 un-booked locations. Proved locations and probable locations account for drilling locations that have associated proved and/or probable reserves, as applicable. Un-booked locations are internal estimates based on prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Un-booked locations do not have attributed reserves or resources. While certain of the un-booked drilling locations have been de-risked by drilling existing wells in relative close proximity to such un-booked drilling locations, the majority of un-booked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and, if drilled, there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Reserves Disclosure. All reserve references in this press release are "Company interest reserves". Company interest reserves are the Company's total working interest reserves before the deduction of any royalties and including any royalty interests payable the Company. It should not be assumed that the present worth of estimated future cash flow presented herein represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Tamarack's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

Oil and Gas Metrics. This press release contains metrics commonly used in the oil and natural gas industry, such as operating field netback, operating netback, development capital, F&D costs, FD&A costs, recycle ratio, reserve life index and net asset value.

"**Operating field netback**" equals total petroleum and natural gas sales less royalties and operating costs calculated on a boe basis.

"**Operating netback**" is the operating field netback with realized gains and losses on commodity derivative contracts.

"**Development capital**" means the aggregate exploration and development costs incurred in the financial year on reserves that are categorized as development. Development capital presented herein excludes land and capitalized administration costs and also includes the cost of acquisitions and capital associated with acquisitions where reserve additions are attributed to the acquisitions.

"**Finding and development costs**" are calculated as the sum of field capital plus the change in FDC for the period divided by the change in reserves that are characterized as development for the period and "finding, development and acquisition costs" are calculated as the sum of field capital plus acquisition capital plus the change in FDC for the period divided by the change in total reserves, other than from production, for the period. Both finding and development costs and finding development and acquisition costs take into account reserves revisions during the year on a per boe basis. The aggregate of the exploration and development costs incurred in the financial year and changes during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. Finding and development costs both including and excluding acquisitions and dispositions have been presented in this press release because acquisitions and dispositions can have a significant impact on Tamarack's ongoing reserves replacements costs and excluding these amounts could result in an inaccurate portrayal of the Company's cost structure.

"**Recycle ratio**" is measured by dividing the operating netback for the applicable period by F&D cost per boe for the year. The recycle ratio compares netback from existing reserves to the cost of finding new reserves and may not accurately indicate the investment success unless the replacement reserves are of equivalent quality as the produced reserves.

"**Reserve life index**" is calculated as total Company interest reserves divided by annual production.

"**Net asset value**" is based on present value of future net revenues discounted at 10% before tax on reserves, plus the Company's internally estimated undeveloped land value, net of estimated net debt at year end divided by the fully diluted shares outstanding at year end.

These terms have been calculated by management and do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Tamarack's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this press release, should not be relied upon for investment or other purposes.

Forward-Looking Information

This press release contains certain forward-looking information (collectively referred to herein as "forward-looking statements") within the meaning of applicable Canadian securities laws. Forward-looking statements are often, but not always, identified by the use of words such as "target", "plan", "continue", "intend", "ongoing", "estimate", "expect", "may", "should", or similar words suggesting future outcomes. More particularly, this press release contains statements concerning: Tamarack's business strategy, objectives, strength and focus; an increase in capital efficiencies, cost cutting initiatives and netbacks; the ability of the Company to achieve drilling success consistent with management's expectations; strategies to minimize exposure to Alberta gas market fluctuations, including hedging and diversifying gas sales; drilling plans including the timing of drilling; the expansion of the oil battery in Veteran; the Viking Pipeline Project and the timing and effects thereof; the NCIB; the payout of wells and the timing thereof; oil and natural gas production levels; timing and level of 2018 capital expenditures; F&D costs and FD&A costs, including FDC; 2018 exit debt; forecast 2018 annual production range and liquid weighting percentage; 2018 production guidance; 2018 drilling program; and shareholder returns. The forward-looking statements contained in this document are based on certain key expectations and assumptions made by Tamarack relating to prevailing commodity prices, the availability of drilling rigs and other oilfield services, the cost of such oilfield services, the timing of past operations and activities in the planned areas of focus, the drilling, completion and tie-in of wells being completed as planned, the performance of new and existing wells, the application of existing drilling and fracturing techniques, the continued availability of capital and skilled personnel, the ability to maintain or grow the banking facilities and the accuracy of Tamarack's geological interpretation of its drilling and land opportunities. Although management considers these assumptions to be reasonable based on information currently available to it, undue reliance should not be placed on the forward-looking statements because Tamarack can give no assurances that they may prove to be correct.

By their very nature, forward-looking statements are subject to certain risks and uncertainties (both general and specific) that could cause actual events or outcomes to differ materially from those anticipated or implied by such forward-looking statements. These risks and uncertainties include, but are not limited to: risks associated with the oil and gas industry (e.g. operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures); commodity prices; the uncertainty of estimates and projections relating to production, cash generation, costs and expenses; health, safety, litigation and environmental risks; and access to capital. Due to the nature of the oil and natural gas industry, drilling plans and operational activities may be delayed or modified to react to market conditions, results of past operations, regulatory approvals or availability of services causing results to be delayed. Please refer to Tamarack's AIF for additional risk factors relating to Tamarack. The AIF can be accessed either on Tamarack's website at www.tamarackvalley.ca or under the Company's profile on www.sedar.com.

The forward-looking statements contained in this press release are made as of the date hereof and the Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, except as required by applicable law. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

This press release contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Tamarack's prospective results of operations, production, net debt, debt adjusted production per share, net debt to adjusted funds flow ratio, adjusted funds flow netbacks, operating netbacks, operating costs, capital efficiencies, capital expenditures and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs and the assumption outlined in the Non-IFRS measures section below. FOFI contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about Tamarack's anticipated future business operations. Tamarack disclaims any intention or obligation to update or revise any FOFI contained in this press release, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law. Readers are cautioned that the FOFI contained in this press release should not be used for purposes other than for which it is disclosed herein.

Non-IFRS Measures

Certain financial measures referred to in this press release, such as net debt, adjusted funds flow, net debt to annualized adjusted funds flow, debt adjusted production per share, capital efficiency, cash flow, adjusted funds flow netbacks and net debt to adjusted funds flow ratio are not prescribed by IFRS. Tamarack uses these measures to help evaluate its financial and operating performance as well as its liquidity and leverage. These non-IFRS financial measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers.

> "Net debt" is calculated as long-term debt plus working capital surplus or deficit adjusted for risk management contracts.
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> "Adjusted funds flow" is calculated based on cash flows from operating activities before changes in non-cash working capital, transaction costs and abandonment expenditures are incurred.
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> "Net debt to annualized adjusted funds flow" is calculated as net debt divided by annualized adjusted funds flow.
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> "Debt-adjusted production per share" represents the Tamarack's production per share after adjusting for debt.
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> "Capital efficiency" represents Tamarack's capital and production costs per day calculated on a per boe basis.
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> "Cash flow" is determined as gross oil, natural gas and natural gas liquids revenues including realized gains on commodity risk management contracts, less the following: royalties, operating costs, transportation costs, general and administrative costs and finance expenses.
>
> "Adjusted funds flow netbacks" equals adjusted funds flow divided by the total sales volume and reported on a per boe basis.
>
> "Debt to cash flow ratio" is calculated as debt divided by cash flow.

Please refer to the MD&A for additional information relating to non-IFRS measures. The MD&A will be filed under the Company's profile on www.sedar.com and will be available on Tamarack's website at www.tamarackvalley.ca.

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